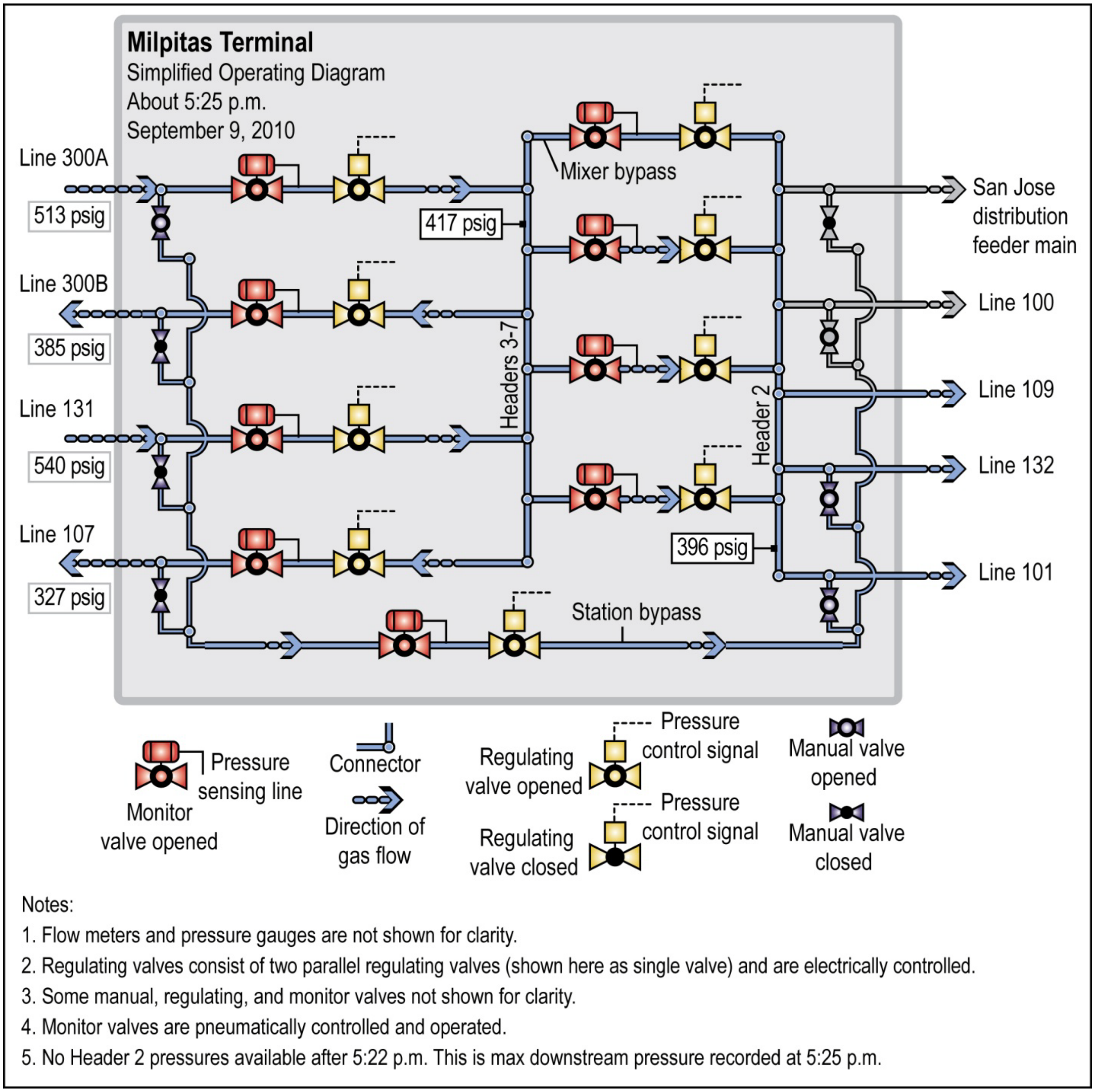

Figure 8b. Valve configuration at the Milpitas Terminal about 5:25 p.m.

At 5:52 p.m., the senior SCADA coordinator asked SCADA operator D to lower the upstream set points for gas supplying the Milpitas Terminal. When the Milpitas technician called operator D to report that the monitor valves were shut on Line 300B, operator D stated that his console was showing almost 500 psig on downstream headers[20] 3–7. He asked the Milpitas technician to place a pressure gauge on Line 132 to get a reading of the pressure leaving the Milpitas Terminal.

[20] A header is a common pipeline, typically of larger diameter, where two or more other pipelines combine through "T" connections. Headers are typically required when multiple redundant inlet sources are used to feed a single downstream location.

At 6:02 p.m., operator D commented to a SCADA operator at the Brentwood facility, “we’ve got a major problem at Milpitas and we’ve over pressured the whole peninsula.” At 6:04 p.m., the senior SCADA coordinator informed the supervisor at the Milpitas Terminal that the pressure on the incoming lines at the Milpitas Terminal had been lowered to 370 psig. At the same time, the Milpitas technician reported to SCADA operator C that he had manually read a pressure of 396 psig on outgoing Line 132. High-high pressure alarms continued to appear in the SCADA system until just after the rupture.

1.1.3 The Rupture

SCADA data indicate that the rupture occurred about 6:11 p.m., when the pressures on Line 132 upstream of Martin Station (7 miles downstream from the rupture site) rapidly decreased from a high of 386 psig. At the same time, a pressure of 386.4 psig was recorded at Half Moon Bay (located about 10 miles upstream of the rupture). By 6:15 p.m., Martin Station generated the first low pressure alarm for Line 132, followed 20 seconds later by another alarm (150 psig). These low-pressure alarms occurred while SCADA operator D was on the phone with a SCADA operator at the Brentwood facility, who alerted him to the low pressures. By 6:36 p.m., the Line 132 pressure at the Martin Station was 50 psig. The pressures in Lines 101 and 109, which are interconnected to Line 132, also decreased but at a slower rate than Line 132.

1.2 Emergency Response

The first 911 call reporting an explosion was received about 6:11 p.m. Many subsequent 911 calls were received from residents and police officers reporting a fire, a gas station explosion, and a possible airplane crash. San Bruno Police Department resources were dispatched, and the first police unit arrived on scene about 6:12 p.m. The first San Bruno Fire Department (SBFD) firefighters to respond had heard the explosion and seen the fire from their station, which was about 300 yards from the accident site. They had reported the fire and were preparing to respond just as the initial dispatch (first alarm[21]) was issued. They were immediately en route and on scene about 6:13 p.m. (See figure 9.)

About the same time, 6:13 p.m., some residents began self evacuating from the accident area. Police officers then began securing the area and conducting evacuations south and north of the fire. At 6:16 p.m., police officers requested that California Highway Patrol troopers divert traffic from the scene. Troopers began closing highways in the immediate area.

[21] A total of six alarms were requested as firefighters responded to various locations surrounding the accident area.

Figure 9. Firefighters approaching accident scene.

At 6:18 p.m., an off-duty PG&E employee notified the PG&E dispatch center in Concord, California, of an explosion in the San Bruno area. Over the next few minutes, the dispatch center received additional similar reports.

About 6:20 p.m., the initial incident commander, a Millbrae Fire Department battalion chief, arrived on scene. When the SBFD chief later arrived on scene,[22] he assumed incident command. A battalion chief from the North County Fire Authority was designated as the deputy incident commander.[23] Fire operations were supervised by a Millbrae Fire Department division chief and were organized into area commands.[24] Battalion chiefs supervised each area. A representative from the county dispatch center responded to the accident area, and requests for additional response resources were relayed through this representative.

At 6:23 p.m., 5 minutes after the PG&E dispatch center received the first call reporting an explosion in the San Bruno area, a dispatcher sent a gas service representative (GSR) working in

[22] The SBFD chief's arrival time was not recorded in any of the documentation provided to the National Transportation Safety Board (NTSB).

[23] Forty-two local, county, state, and Federal fire departments assisted in the accident response.

[24] Area command is a command organization established to oversee the management of large or multiple incidents.

Daly City (about 8 miles from San Bruno) to confirm the report, as required by PG&E procedures. [25]

About the same time, a PG&E supervisor (supervisor 1) saw the accident fire while driving home from work. He called the PG&E dispatch center, reported the fire, and then proceeded to the scene.

By 6:24 p.m., firefighters responding to the south side of the accident area had reported to incident command that hydrants were dry. About the same time, firefighters responding to the north side discovered that the explosion had damaged a water line. To address this, firefighters established water supplies using 1,000–2,000 feet of large-diameter supply hose at two locations.

At 6:27 p.m., a PG&E dispatcher called the SCADA center and asked SCADA operator C if the SCADA center staff had observed a pressure drop "at a station in [the San Bruno] area." The dispatcher stated that he had received reports of a flame shooting up in the air accompanied by a sound similar to a jet engine and that a PG&E supervisor and a GSR had been dispatched to the area. Operator C replied that the SCADA center had not received any calls about the incident. At 6:29 p.m., the senior SCADA coordinator informed a SCADA coordinator at the Brentwood facility that there had been a gas line break and further stated that there had been an overpressure event at the Milpitas Terminal earlier. Reports of a plane crash, a gas station explosion, or some combination of the two persisted throughout the initial hours of the emergency response. By 6:30 p.m., some staff at the SCADA center realized that there had been a rupture along Line 132 in the San Bruno area. However, they did not know the exact location of the rupture and continued to try to identify it.

About 6:30 p.m., the on-scene fire operations supervisor declared the incident a multi-casualty incident. Soon after, a medical group was established, and medical units were positioned north and south of the accident scene.

At 6:31 p.m., SCADA operator B reported to dispatch that there was "a major pressure drop at a station up in that area [near San Bruno]."

About 6:35 p.m., an off-duty PG&E gas measurement and control mechanic (mechanic 1), who was qualified to operate mainline valves, saw media reports about the fire. Suspecting a transmission line break, he notified the PG&E dispatch center, and proceeded to the PG&E Colma yard[26] to obtain his service truck and the tools necessary to shut off mainline

[25] PG&E procedures require the GSR to evaluate the danger to life and property, assess damage, and make or ensure that conditions are safe. The procedures also require field personnel to notify a field service supervisor, a dispatcher, a gas maintenance and construction supervisor, or an on-call gas supervisor. Nowhere does the procedure instruct field personnel, the dispatch center, or the SCADA center to contact emergency services through 911 or other means. The procedure does not discuss the involvement of city or emergency officials. Notifications that are outlined in the procedure focus on company personnel and supervisors only. On June 8, 2011, the NTSB issued safety recommendations relating to this PG&E procedure. For more information, see Section 1.12, "Previous NTSB Safety Recommendations."

[26] The Colma yard is a small PG&E facility about 4.5 miles from San Bruno, where equipment and vehicles are stored.

valves. Mechanic 1 lived only a couple of miles from the accident site and the Colma yard. While en route to the Colma yard, mechanic 1 received a call from a supervisor (supervisor 2) directing him to report to the yard and to contact a second mechanic (mechanic 2) to do the same. Before mechanic 1 could place the call, mechanic 2 called him to check on his well being. Both mechanics proceeded to the Colma yard.

Meanwhile, another PG&E supervisor (supervisor 3), who lived about 4 miles from the rupture site, learned of the explosion and fire through media reports and notified the SCADA center. He then proceeded to the accident site.

About 6:40 p.m., firefighters requested two water tenders,[27] which were used as water sources and assigned as needed to various locations around the fire. A California wildfire battalion chief was assigned as a liaison to oversee the water tenders.

Supervisor 1 was the first PG&E employee on scene. The GSR, who had been delayed in traffic, arrived shortly thereafter. Both were confirmed on scene at 6:41 p.m., with supervisor 3 following soon after. However, none of these three PG&E first responders were qualified to operate mainline valves. Upon arrival, supervisor 3 and supervisor 1 informed firefighters of their presence as PG&E representatives on scene.

At 6:48 p.m., supervisor 1 called the PG&E dispatch center to request that gas and electric crews respond to the scene.

Mechanic 1 arrived at the Colma yard about 6:50 p.m., and mechanic 2 arrived soon after. They obtained a map showing the location of pipeline valves in the area and watched further news reports regarding the accident. Processing the visual information, mechanic 1 recognized the rupture as occurring in Line 132 and called a supervisor (supervisor 4) to tell him he was going to isolate the rupture. Supervisor 4 authorized the action.

By 6:55 p.m., supervisor 3 had contacted another supervisor (supervisor 5) who activated the PG&E operations emergency center[28] in San Carlos and declared supervisor 3 the deputy incident commander.

About 7:06 p.m., the two PG&E mechanics left the Colma yard, driving toward the first mainline valve (at MP 38.49) that they planned to close; they were joined en route by a supervisor (supervisor 6). The three arrived at the first valve location by 7:20 p.m.

[27] A water tender is a firefighting apparatus used to shuttle, store, and supply water.

[28] The San Carlos operations emergency center command post is permanently equipped with computers, desks, and communication equipment. PG&E's emergency plans define the specific responsibilities of personnel staffing the center. The center directed field resources within the immediate San Bruno area. Later, a larger operations emergency center in the San Francisco headquarters was also activated because of the extent of the emergency. The San Francisco emergency operations center is a central location from which the emergency response activities of the local operating department are prioritized and coordinated.

Meanwhile, the SCADA center and dispatch center staff were occupied with making outgoing calls to brief PG&E departments and officials of the incoming information, such as the rumors of an airplane crash and a gas station explosion. Between 6:50 and 7:00 p.m., SCADA operators D[29] and B[30] made comments indicating that there had been a break on Line 132, but SCADA operator C made comments indicating uncertainty as to the nature of the accident.[31] During a phone call at 7:07 p.m., operator D responded to a dispatch employee who reported the rumor that there had been a plane crash by saying, "It's easy to believe it's a plane crash. We still have indication that it is a gas line break. We're staying with that. If you talk to the fire department I would inform them of that." There was no indication that the dispatch center passed this information to the fire department.

At 7:22 p.m., at the direction of supervisor 3, supervisor 1 contacted the PG&E dispatch center to convey that although it was still unconfirmed, the incident was likely a reportable gas fire. Within minutes, the dispatch center relayed this information to the SCADA center; the SCADA center confirmed that Line 132 was involved.

At 7:27 p.m., supervisor 6, who was with the two mechanics, requested that the SCADA center close two valves at the Martin Station. SCADA operator D remotely closed the valves downstream of the rupture by 7:29 p.m., which stopped the gas flow from north to south. (See figure 10.)

By 7:30 p.m., the two mechanics had manually closed the mainline valve (at MP 38.49) south (upstream) of the rupture, stopping the gas flow at that location. By 7:42 p.m., 91 minutes after the rupture, the intensity of the fire had decreased such that firefighters could approach the rupture site and begin containment efforts.

By 7:46 p.m., the two mechanics, with some assistance from supervisor 6, had manually closed two more valves downstream of the rupture (at MPs 40.05 and 40.05-2) at the Healy Station. Closing these valves isolated the ruptured section of pipe.

About 7:57 p.m., a PG&E pipeline engineer informed the SCADA center staff that the rupture in Line 132 had occurred at MP 39.33[32] and explained that several mainline valves had been closed to isolate the break. He also told the staff that the downstream crosstie valves between Lines 109 and 132 had been opened to reestablish gas flow to the Martin Station. About the same time, the San Bruno Recreation Center, staffed by the American Red Cross, was opened as a shelter for evacuees.

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[29] During a phone call beginning at 6:53 p.m., SCADA operator D said in a conversation with the on-site SCADA supervisor, "Yeah, absolutely we believe it's a break on line 132."

[30] During a phone call beginning at 6:55 p.m., SCADA operator B said to a dispatch employee, "Transmission line 132 is busted."

[31] During a phone call beginning at 6:55 p.m., SCADA operator C stated to supervisor 3, "I don't think it is [a] transmission [line]."

[32] PG&E has since clarified that the rupture occurred at MP 39.28.

By 11:32 p.m., additional PG&E crews had manually closed two distribution line valves and squeezed (that is, pinched with hand tools) three more distribution lines to stop the gas-fed house fires surrounding the pipeline rupture.

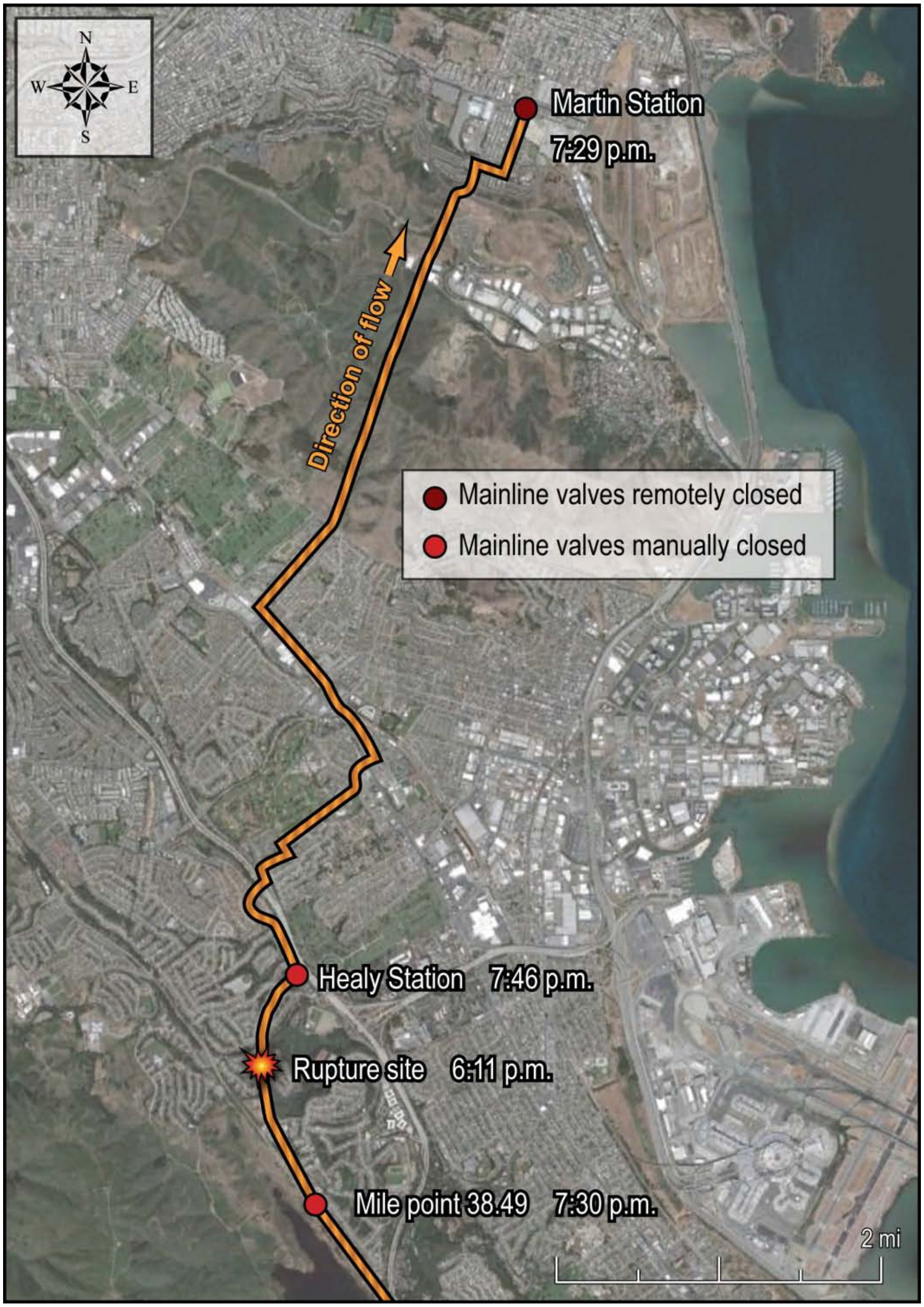

Figure 10. Location of valve closures.

Although the gas flow through the transmission line break and several local distribution lines had been stopped, the resulting fires continued. Firefighters declared 75 percent of all active fires to be contained about 4:24 a.m. on September 10. Fire operations continued to extinguish fires and monitor the accident area for hot spots until about 8:00 p.m. on September 11, when the SBFD transferred incident command to the San Bruno Police Department.

During the 50 hours following the accident, about 600 firefighting (including emergency medical service) personnel and 325 law enforcement personnel responded. Fire crews and police officers conducted evacuations and door-to-door searches of houses throughout the response. In total, about 300 houses were evacuated. Firefighting efforts included air and forestry operations. Firefighters, police officers, and members of mutual aid organizations also formed logistics, planning, communications, finance, and damage assessment groups to orchestrate response efforts and assess residential damage in the accident area.

1.3 Injuries

As a result of the pipeline rupture and fire, 8 people were killed, 10 people sustained serious injuries, and 48 people sustained minor injuries. (See table 1.) For five of the fatalities, the cause of death was "generalized conflagration effects," and for the remaining three, the cause of death was "undetermined." Twenty-one people were transported to hospitals by ambulance, including three firefighters who were treated for smoke inhalation. Forty-five other people were transported to hospitals by private vehicle.

Table 1. Injuries.

Injury Type[a]	Number
Fatal	8
Serious	10
Minor	48
Total	66

[a] Title 49 CFR 830.2 defines fatal injury as any injury that results in death within 30 days of the accident and serious injury as an injury that (1) requires hospitalization for more than 48 hours, commencing within 7 days of the date the injury was received; (2) results in a fracture of any bone (except simple fractures of fingers, toes, or nose); (3) causes severe hemorrhages or nerve or tendon damage; (4) involves any internal organ; or (5) involves second- or third-degree burns, or any burn affecting more than 5 percent of the body surface.

1.4 Damage

The rupture of Line 132 released an estimated 47.6 million standard cubic feet of natural gas, created a 72-foot-long by 26-foot-wide crater, and ejected a 28-foot piece of pipe weighing 3,000 pounds, which came to rest about 100 feet away. The gas ignited and caused an explosion. As previously noted in section 1.2, "Emergency Response," the fire was declared about 75 percent contained at 4:24 a.m. on September 10, 2010, about 10 hours and 13 minutes after the accident occurred.

The fire damage extended to a radius of about 600 feet from the pipeline blast center, mostly spreading in a northeast direction. (See figure 11.) The fire affected 108 houses—38 of which were destroyed, 17 of which received severe-to-moderate damage, and 53 of which received minor damage.[33] (See figure 12.) In addition, 74 vehicles were damaged or destroyed. (See figure 13.) The burned area also included a park with woodlands and a playground. According to PG&E, the cost to repair the pipeline was about $13,500,000,[34] and the loss of natural gas accounted for $263,000.

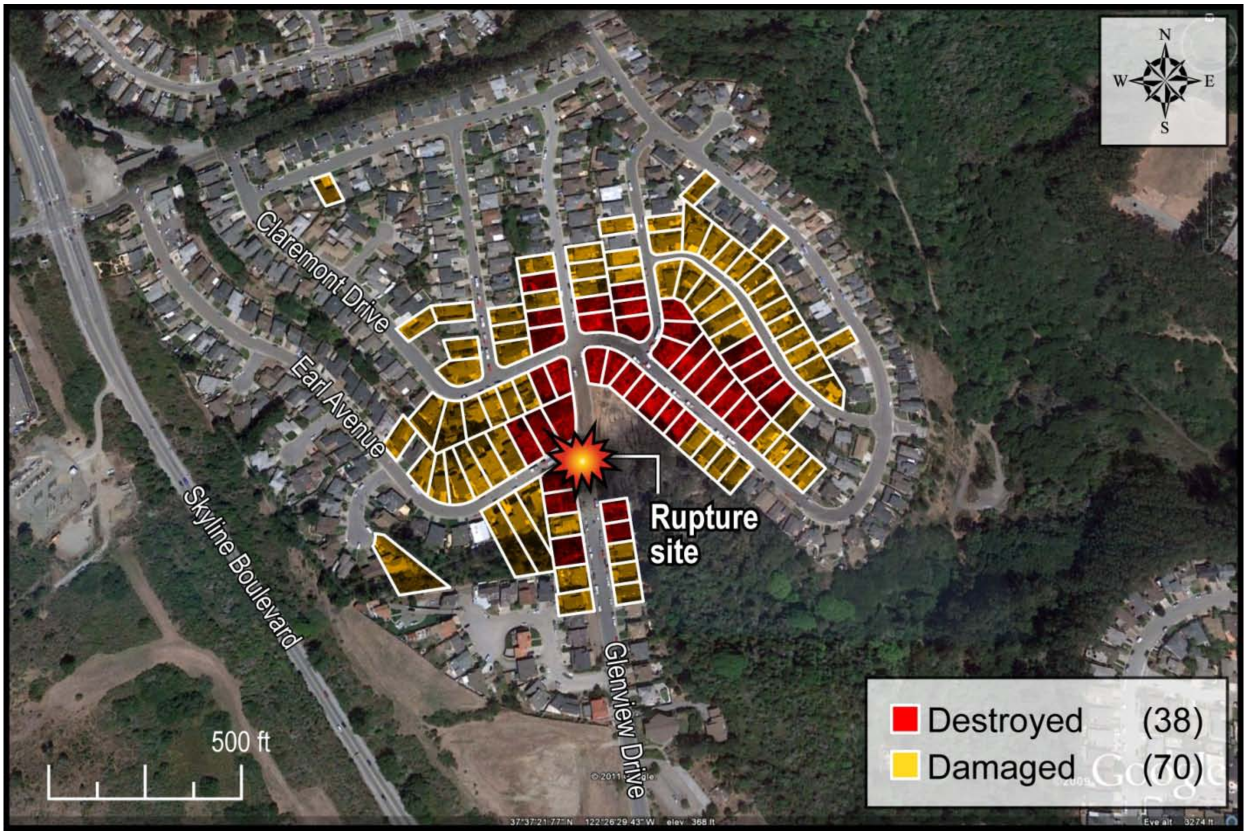

Figure 11. Picture showing area of damage from blast and fire.

[33] The city of San Bruno used the following damage categories to classify structural damage to houses at the accident site: (1) *severe* indicated that a house was not safe to occupy and most likely would need to be demolished or completely renovated prior to occupancy, (2) *moderate* indicated that a house had substantial damage and repairs would be necessary prior to occupancy, and (3) *minor* indicated that a house had the least amount of damage and could be legally occupied while repairs were being made.

[34] PG&E has reported it will not be repairing Line 132 in the area of the accident.

Figure 12. Picture of destroyed houses.

Figure 13. Picture of a burned car in front of several destroyed houses.

1.5 Meteorological Information

Air temperature and moisture information was retrieved from the Automated Surface Observing System (ASOS) at San Francisco International Airport (KSFO), located about 3 miles to the east of the accident site at an elevation of 13 feet. Air temperature at the accident time (6:11 p.m.) was about 64° F and had decreased to 59° F by midnight. Dew point temperatures remained consistent at about 52° F throughout this period. The wind across the northern and central portion of the San Francisco peninsula was estimated to have been from the west with magnitudes from 15–25 knots (which equates to about 17–29 mph) from the accident time through about 10:00 p.m.[35] After 10:00 p.m., the wind magnitude decreased at the KSFO ASOS. At the NTSB's request, a professional meteorologist familiar with the local terrain and micro-climates reviewed the small-scale wind flow for the accident neighborhood. This expert indicated that the wind in the accident area would have been from the northwest, aligned with Skyline Boulevard. Slightly northwest of the accident location, a branching of the northwesterly wind would have brought a weaker flow across the accident neighborhood from the west-northwest, with eddying also occurring. The expert estimated that wind speeds between 6:00 and 9:00 p.m. would have been 15–20 mph.

1.6 Personnel Information

1.6.1 Milpitas Technician and Other Workers at the Milpitas Terminal

The Milpitas technician had been on duty for about 12 hours 11 minutes when the accident occurred.[36] He had been hired by PG&E on December 26, 1984. During his employment, the Milpitas technician had successfully completed 171 training courses. He had taken four courses specific to his position in the 17 months before the accident.[37] The electrical contractor had been on duty for 4 hours 41 minutes at the time of the accident.

After the accident, PG&E had the four workers at the Milpitas Terminal provide specimens for toxicological testing, pursuant to 49 CFR 199.105 and 199.225.[38] These

[35]These wind magnitude estimates were based primarily on data retrieved from the KSFO ASOS and observations made by commercial aircraft near KSFO at altitudes close to the accident elevation.

[36] Investigators collected detailed work/rest information for all of the employees at the Milpitas Terminal and the SCADA center who were on duty at the time of the accident. This information included awakening and to bed times, time awake, and time on duty on the day of the accident, as well as information from each employee about the quality of their overall rest, whether they had medical issues related to sleep, and whether they had received training about fatigue. For more information, see the Human Performance Group Chairman's Factual Report and Addendum in the NTSB public docket for this accident.

[37] Investigators collected information about training courses taken by each of the PG&E employees at the Milpitas Terminal and the SCADA center who were on duty at the time of the accident. (No training information was available for the contractor.) According to PG&E, available training courses specific to their duties included gas clearance process initial training, gas clearance process training, and refresher gas clearance process training. Training records indicated that each employee had successfully completed the gas clearance process initial training, six of the employees had also successfully completed the gas clearance process training, and one had successfully completed refresher gas clearance process training. For more information, see the Human Performance Group Chairman's Factual Report in the NTSB public docket for this accident.

[38] The California Public Utilities Commission (CPUC) requires PG&E to adhere to postaccident toxicological protocol consistent with PHMSA regulations.

regulations require drug and alcohol testing for each employee whose performance either contributed to the accident or cannot be completely discounted as a contributing factor, and further state that the decision not to administer a test “shall be based on the operator’s determination, using the best available information at the time of the determination, that the covered employee’s performance could not have contributed to the accident.” (PHMSA has not issued any guidance regarding the type of analysis or justification that would be acceptable in reaching such a determination.) According to section 199.105, drug tests are to be conducted as soon as possible but no later than 32 hours after an accident. According to section 199.225, alcohol testing is to be conducted as soon as practicable after an accident, and if it is not done within 2 hours of an accident, the operator is required to prepare and maintain a record stating the reasons the test was not promptly administered. The regulation further states that if the test is not administered within 8 hours of the accident, the operator shall cease attempts to do so and state in the record the reasons for not administering the test.

PG&E notified its testing contractor at 12:30 a.m. on September 10 that drug and alcohol testing services were needed, and informed her that the 8-hour time frame for alcohol testing would likely be exceeded but instructed her to collect the specimens anyway. The contractor reported to NTSB investigators that she was never made aware of, nor did she inquire about, the time of the rupture. She indicated she was aware of the regulatory 8-hour time limit for alcohol testing.

The Milpitas technician provided a urine specimen at 3:10 a.m. on September 10. The specimen was then tested for the following illegal drugs: cannabinoids, cocaine metabolites, opiates, amphetamines, and phencyclidine. The test results were negative. He also took a breathalyzer test to detect ethyl alcohol in his system. The test was administered at 3:36 a.m. on September 10.

Between 3:51 and 5:21 a.m. on September 10, specimens for drug and alcohol testing were also collected from two other PG&E employees and a contractor who had been on duty at the Milpitas Terminal when the accident occurred; the drug test results were negative.

No documentation was generated as to why alcohol testing was not promptly administered in accordance with 49 CFR 199.205. The CPUC indicated that it was investigating the untimely alcohol testing for possible enforcement action.

1.6.2 SCADA Operators

As previously noted, three operators were staffing the SCADA center at the time of the pipeline rupture, and all three were involved in responding to the events surrounding the accident. SCADA operator D, who served as the primary point of contact with the Milpitas technician, had been on duty for about 12 hours 11 minutes when the accident occurred and remained on duty for an additional 3 hours 20 minutes after the rupture. He had been hired by PG&E on June 18, 1979. Over the years, operator D had successfully completed 104 training courses. During the 17 months before the accident, he had taken three courses specific to his position.

SCADA operator C had been on duty for about 12 hours 41 minutes when the accident occurred and remained on duty for an additional 3 hours 20 minutes after the rupture. He had been hired by PG&E on December 8, 1983. Operator C had successfully completed 76 training courses while employed with PG&E. During the 18 months before the accident, he had taken three courses specific to his position.

SCADA operator B had been on duty for about 13 hours 6 minutes when the accident occurred and remained on duty for an additional 3 hours 50 minutes after the rupture. He had been hired by PG&E on September 17, 1974. Throughout his career, he had successfully completed 86 training courses. He had taken three courses specific to his position in the 17 months before the accident.

PG&E did not conduct drug or alcohol testing for any of the employees at the SCADA center. PG&E indicated that the SCADA staff were not identified for testing because they were "deemed to be monitoring and responding to the rupture, not contributing to the rupture event."

1.7 Pipeline Information

1.7.1 Line 132

Line 132 originates at the Milpitas Terminal and extends north about 46 miles to the Martin Station.[39] (See figure 14.) Line 132 is one of three gas transmission lines in the PG&E peninsula system. The other two are Lines 101 and 109. In all three lines, gas flow is typically from south to north. The peninsula system includes six crossties that connect the three transmission lines and allow gas to flow between them. (Four of those crossties are shown on figure 14; the two not shown connect Lines 132 and 109 at MPs 29.06 and 31.93.)

[39] Line 132 continues north beyond the Martin Station for a short distance as a distribution line.

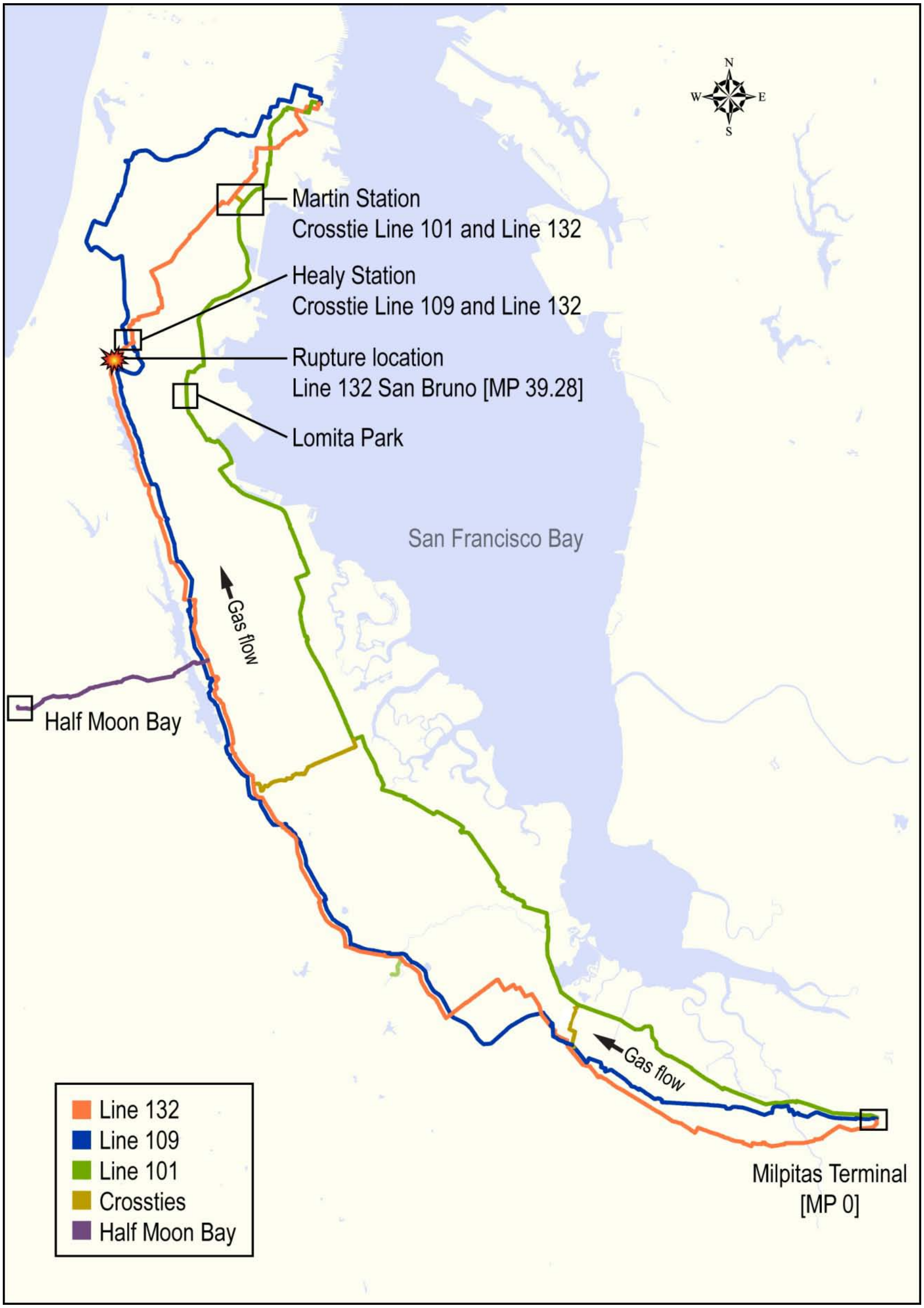

Figure 14. Map showing PG&E peninsula gas transmission lines.

Line 132 was originally constructed in phases, with construction projects in 1944 and 1948. According to the PG&E geographic information system (GIS),[40] Line 132 is made up of 24-, 30-, 34-, and 36-inch-diameter segments of various steel grades with various longitudinal seam weld types, such as double submerged arc welded (DSAW), electric resistance welded (ERW), and seamless (SMLS).

In response to a request for construction records for the 1948 portion of the Line 132 project, PG&E provided more than 18,000 pages of records, including material procurement orders from the Consolidated Western Steel Corporation (Consolidated Western) Maywood, California, plant, accounting records, specifications, foreman journal entries, and radiography receipts. The records indicated that 10 percent of the girth welds[41] were radiographed (that is, x-rayed) at the construction site and inspected according to a set of standards agreed upon by engineers from PG&E and the construction contractor. Radiographs of the girth welds also captured a small portion of the longitudinal welds from each of the two pipe segments joined by the girth weld being radiographed. Records from the 1948 project included logs for 209 radiographs, including 19 rejected welds, 4 of which were reexamined and determined to be acceptable. Those four were all longitudinal welds. Of the remaining 15 rejected welds, 5 were longitudinal welds and 10 were girth welds. An additional 14 girth welds were classified as "borderline."

The foreman's log from the 1948 construction project noted several instances of construction damage, including dents and dent repairs.

After the 1948 installation, the 20- and 24-inch segments of Line 132 were tested for leaks in accordance with the construction contract by introducing air at 100 psig and using a soap and water solution on girth welds. According to construction records, as a final check before introducing gas, the 20- and 24-inch segments were pressured to 100 psig with air and held for 48 hours. Gas was introduced into the 30-inch portion of the line upon completion, and the line was checked "for leaks and breaks."

1.7.2 1956 Relocation Project (Segment 180)

In 1956, PG&E relocated 1,851 feet of Line 132 that had originally been installed in 1948. The relocation was necessary because the existing elevation of Line 132 was incompatible with land grading that had been done in connection with residential housing being built at that location. This relocation, which included the installation of the pipe at the accident location, started north of Claremont Drive and extended south to San Bruno Avenue, and rerouted Line 132 from the east side to the west side of Glenview Drive. (See figure 15.) The relocation work was not contracted out, but rather was performed by PG&E construction crews. Construction documentation provided to the NTSB consisted of about 300 pages of journal vouchers, material transfers, paving receipts, and various other cost accounting sheets. PG&E did

[40] The GIS is a database of pipeline attributes populated by PG&E.

[41] Girth welds, which are typically done at the time of installation in the field, join adjacent pipe pieces and extend around the circumference of the pipe.

not provide any design/material or construction specifications, inspection records, as-built drawings, or radiography reports. A reference to two cases of bar soap "for testing" was the only indication that any type of on-site leak testing of the girth welds may have been performed.

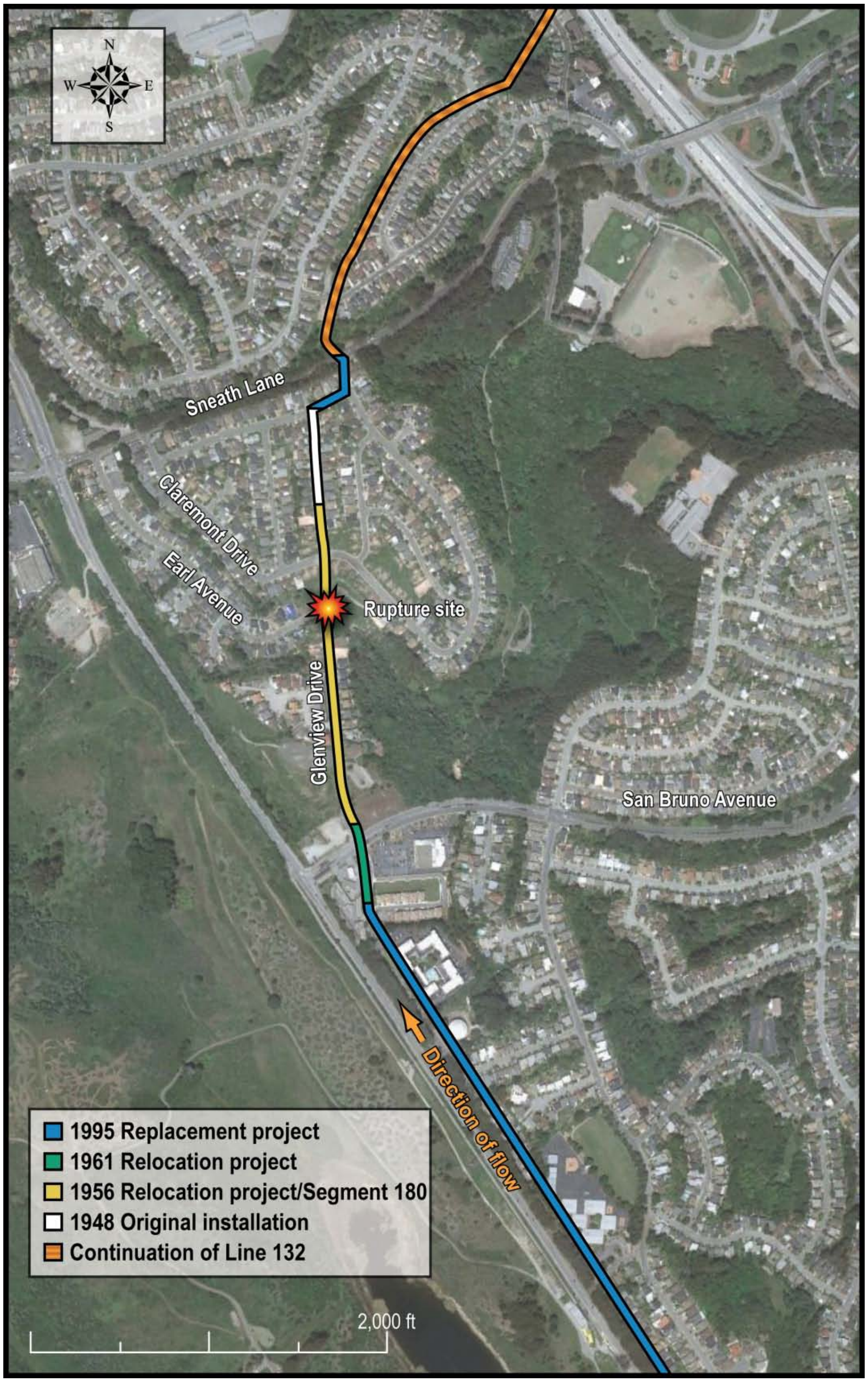

Figure 15. Line 132 installation, relocations, and replacements.

In 1961, PG&E completed a second relocation project on a portion of Line 132 immediately to the south of the 1956 relocation. As a result, 1,742 feet of the original 1,851 feet of pipe from the 1956 relocation project, including the rupture location, remained in operation. In PG&E's records, this segment is known as Segment 180.

At the time of the accident, Segment 180 was documented in the PG&E GIS as 30-inch-diameter seamless steel pipe API 5L X42 with a wall thickness of 0.375 inch, installed in 1956. The manufacturer is listed as "NA," indicating the information was unknown or unavailable. This portion of the GIS database was populated in 1998 using data from a pipeline survey sheet created in 1977. PG&E discovered during the investigation of this accident that the material specification information for Segment 180 on the 1977 pipeline survey sheet had been obtained from accounting records rather than engineering records. Specifically, the source of the information was a 1956 journal voucher used to allocate material expenses from one construction job to another, which contained an erroneous material description.

After the accident, NTSB investigators discovered that Segment 180 was not X42 seamless pipe, as stated in the GIS database, and that other documents relating to the 1956 project had correctly indicated that the pipe intended for use in that project had a DSAW longitudinal seam. The investigation revealed that seamless pipe was not, and still is not, available in diameters larger than 26 inches. The PG&E director of integrity management and technical support acknowledged in postaccident interviews that during the time when the pipe for Segment 180 was purchased, all 30-inch pipe purchased by PG&E would have been DSAW, not seamless. Investigators also discovered that the material code listed on the journal voucher corresponded to X52 pipe, not X42.

The investigation also revealed that the pipeline at the rupture location was made up of six short pipe segments, known as pups, which were welded together circumferentially. None of the pups were X52 pipe. Each pup ranged from 3.5–4.7 feet long. The NTSB Materials Laboratory determined through tensile and chemical composition testing that the material properties in some of the pups did not meet PG&E 1948 material specifications or industry pipeline material specifications for this time period. The GIS database did not reflect the presence of these pups, although it is intended to record each change in material properties as a separate segment. Further, the investigation revealed that several of the pups had partially welded longitudinal seams that left part of the seam unwelded and that several girth welds joining the pups contained multiple weld defects. Examination revealed that the longer pipe pieces (joints) on either side of the sequence of pups were standard X52 DSAW pipe. (For more information about the pups, see section 1.8, "Examination of Accident Pipe.")

As noted earlier in this section, PG&E could not produce any design/material or construction specifications for the 1956 relocation project. PG&E stated its belief that the project followed the standards in the American Society of Mechanical Engineers (ASME)-sponsored code B31.1.8, 1955 edition, *Gas Transmission and Distribution Piping Systems*.[42] In 1955, PG&E's then-superintendent of gas transmission and distribution was an active member of the ASME B31.1.8, 1955 edition, code committee.

According to PG&E, the pipe used was left over from previous purchases of pipe for other construction projects. According to PG&E, between 1947 and 1957, it purchased a total of 320,065 feet of 30-inch pipe from three suppliers. Based on its records search and the characteristics of the accident pipe, including the numbers painted on the inside of the DSAW long joint south of the pups, PG&E indicated its belief that the pipe at the location of the rupture was most likely manufactured by Consolidated Western in 1948, 1949, or 1953 and was originally purchased for Line 153, Line 131, or the 1948 Line 132 project. PG&E stated that Consolidated Western manufactured the pipe for these three projects at its Maywood, California, plant until May 1949, and afterwards at its South San Francisco plant. NTSB investigators examined the records and determined that the pipe used for the 1956 project was assembled from multiple material procurement orders.

The PG&E 1948 specification for 30-inch pipe, the most recently applicable specification at the time of the 1956 relocation project, called for steel pipe with longitudinal seams joined by electric fusion welding (now referred to as submerged arc welding[43]). A PG&E document prepared in 1962, titled "History of Pipe Purchases," states that, beginning in 1948, all purchased pipe with diameters of 20–36 inches would have been DSAW pipe. For pipe with 0.375-inch-thick walls, it specified that wall thickness could not be less than 90 percent of the specified thickness and that any defect reducing the wall thickness to less than this amount would be considered injurious. It also specified a minimum yield strength of 52,000 psi. Regarding hydrostatic pressure tests at the time of manufacture (that is, at the pipe mill), the specification stated that—

> each length of pipe…including jointers, shall be tested to a hydro-static pressure which will produce a stress of 90% of the specified minimum transverse yield strength [1170 psi in the case of 30-inch pipe with a wall thickness of 0.375 inch], which pressure shall be maintained for not less than ten seconds. …While under pressure, the pipe length shall be struck a blow with a two-pound hammer, or its equivalent, near both ends of the weld.

The PG&E specification further provided that 95 percent of the finished pipe sections were to be between 30 feet 6 inches long and 31 feet 4 inches long. Consistent with

[42] All versions of the ASME-sponsored codes for pressure piping are referred to in this report as ASME codes, even though several other organizations have also been associated with their development over time. The ASME code for pressure piping was originally developed in cooperation with the American Engineering Standards committee, which later changed its name to the American Standards Association, and then to the American National Standards Institute, Inc.

[43] Submerged arc welding is a form of arc welding where the filler wire and the pipe seam are submerged in a bed of pelletized flux. The flux protects the weld from impurities while it is in its molten state.

API standards at that time, it stated that no more than 5 percent of the order could consist of jointers, defined in the specification as two (or more)[44] pieces of pipe joined by welding, and that a jointer could not contain pipe lengths measuring less than 5 feet. At the NTSB's investigative hearing, the PG&E director of integrity management and technical support testified that he believed the accident segment of pipe was a jointer manufactured at a mill.

In July 1949, Moody Engineering Company submitted a report to PG&E on the supervision and inspection of the manufacture of 100,000 feet (3,222 pieces) of 30-inch-diameter pipe by Consolidated Western's Maywood, California, manufacturing plant. The report explained the manufacturing process, the chemical and physical properties of the steel, and the hydrostatic pressure test procedure used at the factory. According to the report, based on inspections of each piece of pipe, 244 pieces were repaired to meet PG&E specifications, and 19 pieces were permanently rejected. Moody Engineering Company concluded that the pieces that had been accepted met PG&E specifications and were shipped in March and April 1949.

1.7.3 Multiyear Replacement Project and Seismic Risk

According to the PG&E GIS, in 1995, PG&E replaced several sections of Line 132, including segments that ended about 565 feet to the south and about 610 feet to the north of Segment 180. These replacements were part of a multiyear replacement project on the peninsula lines to address seismic hazards. Some segments of Lines 109 and 132 crossed the San Andreas Fault and were therefore rerouted to reduce seismic risk. Segment 180 does not cross the fault, and a 1992 report prepared by the PG&E geosciences department in connection with the replacement project indicated that Segment 180 had a low-to-moderate seismic risk. The subsequent risk assessments of Segment 180 assigned a score of 0 for any "ground movement" threat. (For more information on threat scores and risk assessment, see section 1.9.4, "PG&E Risk Management/Integrity Management Program.") A low seismic risk for the accident area was also indicated by a February 2011 report prepared for PG&E under contract by TRE Canada, a company that specializes in measuring ground deformation using satellite imagery. TRE Canada analyzed the Earl Avenue and Glenview Drive area from May 1992–August 2010 and found that the accident area did not experience any significant vertical movement during that time.

According to a PG&E public information fact sheet, the purpose of the multiyear project, which began in 1985, was "to maintain safe and reliable gas service to our customers," and it would eventually "replace all aging natural gas pipelines in the system over a 25-year period." In addition to seismic hazard, other factors considered in setting replacement priorities for the project were age, construction factors, and condition of the pipe.

[44] PG&E provided multiple documents containing the specification. In one document, jointers are defined as "two pieces joined by welding," and in another as "two or more pieces joined by welding."

1.7.4 Underground Environment at Accident Location

At the time of the accident, Line 132 was buried underground along the west side of Glenview Drive.[45] Other underground utilities at the accident site included a 6-inch-diameter water line, which crossed about 2.5 feet above Line 132 at the location of the rupture and was destroyed, resulting in the lack of functional fire hydrants near the accident scene. A 10-inch-diameter sanitary sewer line crossed below Line 132 about 108 inches south of pup 1. (The sewer line is discussed further below.) In addition, a 4-inch-diameter gas distribution line ran parallel to Line 132, about 6 feet 9 inches to the west. (See figure 16.) Farther below the buried utilities, at a depth of about 9 feet, was a drainage system with a catch basin running from west to east, which emptied into a canyon just east of the accident location.

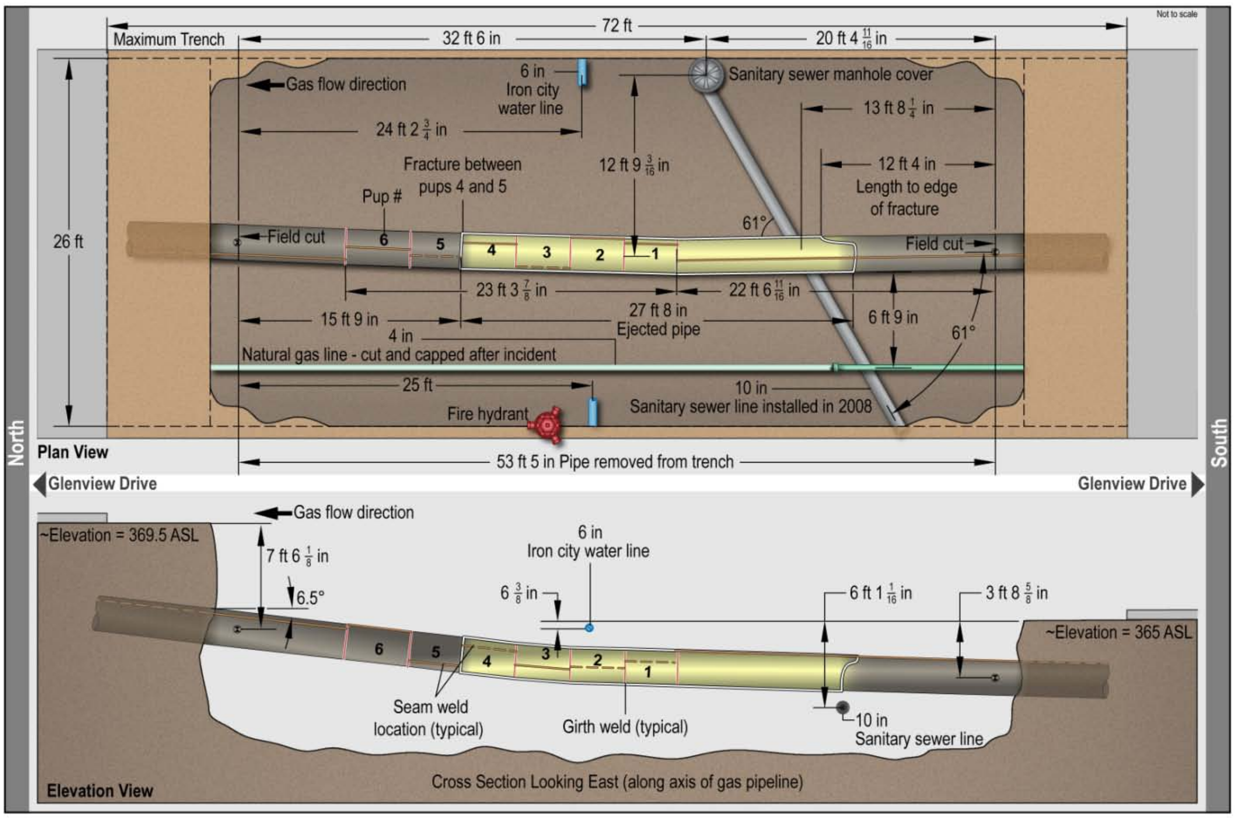

Figure 16. Sketch of underground utilities environment.

1.7.4.1 2008 Sewer Replacement

In June 2008, the city of San Bruno issued a change order to an existing contract to upgrade the sanitary sewer main along Earl Avenue to Glenview Drive. The change order specified that the contractor replace the existing 6-inch vitrified clay sewer pipe with a 10-inch-diameter polyethylene pipe by pneumatic pipe bursting, which is a widely used method of replacing buried pipe without digging an open trench. Two pits are required to install the new

[45] As a result of the rupture, this portion of Line 132 is no longer in service.

pipe: an entry pit (normally a long slender trench to allow the pipe to bend as it is introduced into the ground) and an exit pit (normally a square pit at an existing manhole to allow for the cable, pulley block, and bursting head removal). The bursting head, a conical pneumatic expanding device, is introduced through the entry pit. It travels through the existing pipe, breaking it into pieces and radially expanding the existing hole. The new pipe, attached to the back of the bursting head, is simultaneously pulled into place. The bursting head is pulled by a cable that runs through the existing sewer pipe to the exit pit, through a pulley block, and up to a winch located above the exit pit at street level.

The existing sewer pipe ran underneath Line 132 at the intersection of Earl Avenue and Glenview Drive, requiring an excavation of the sewer pipe on either side of Line 132. The contractor dug a potholing[46] trench that extended about 4 feet or more to the west and 3 feet to the east of Line 132. Further, according to the contractor, in the area where the sewer pipe crossed under Line 132, the old sewer pipe was broken up and removed by hand before the pipe-bursting operation began. The pneumatic expanding device was turned off as it passed under the area where the sewer pipe crossed under Line 132.

Prior to the excavation, the contractor had contacted the local one-call service company[47] and filed the required notices.

The exit pit was located at an existing manhole on Glenview Drive approximately 8 feet from the east side of Line 132. A 10-ton constant tension winch was located at the west wall of the pit.[48] The cable traveled down from the winch, into the exit pit, and over a pulley that was braced near the bottom of the pit against three overlapping sheet pilings. The outer two pilings spanned the full height of the pit and were driven into the floor of the pit at the west wall. The shortest distance from the center of the sheet pilings to the sidewall of Line 132 was estimated to be 7.7 feet. As the cable left the exit pit, it passed under Line 132, through the potholing trench, and continued along the existing sewer pipe to the entry pit.

The pipe bursting began at the entry pit 290 feet to the west on Earl Avenue. A video of the project recorded the sound of the pneumatic bursting and showed the movement of the replacement pipe at the exit pit and the movement of the cable at the winch. Based on the recording, the pneumatic bursting rate was 214 strokes per minute. Based on the video, the replacement pipe pull rate ranged from 0.1–0.2 inches per second. According to the contractor, the maximum load on the winch was 14,000 pounds and the diameter of the cable was 0.562 inch. As the bursting head approached the potholing trench, the pneumatic device was turned off. From there, the replacement sewer pipe was pulled through the potholing trench, underneath Line 132, and up to the exit pit. (See figure 17.)

[46] Potholing refers to holes used when excavating the ground near a utility service to visually locate the utility. Small holes are dug on either side of a pipe with a backhoe until the location of the utility can be visually confirmed.

[47] A one-call, or 811, service is a required notification system used to ensure the identification and marking of buried pipelines before excavation.

[48] Constant tension indicates that the force exerted by the winch on the cable can be set to a constant value, selected by the operator, that otherwise does not vary during the bursting process.

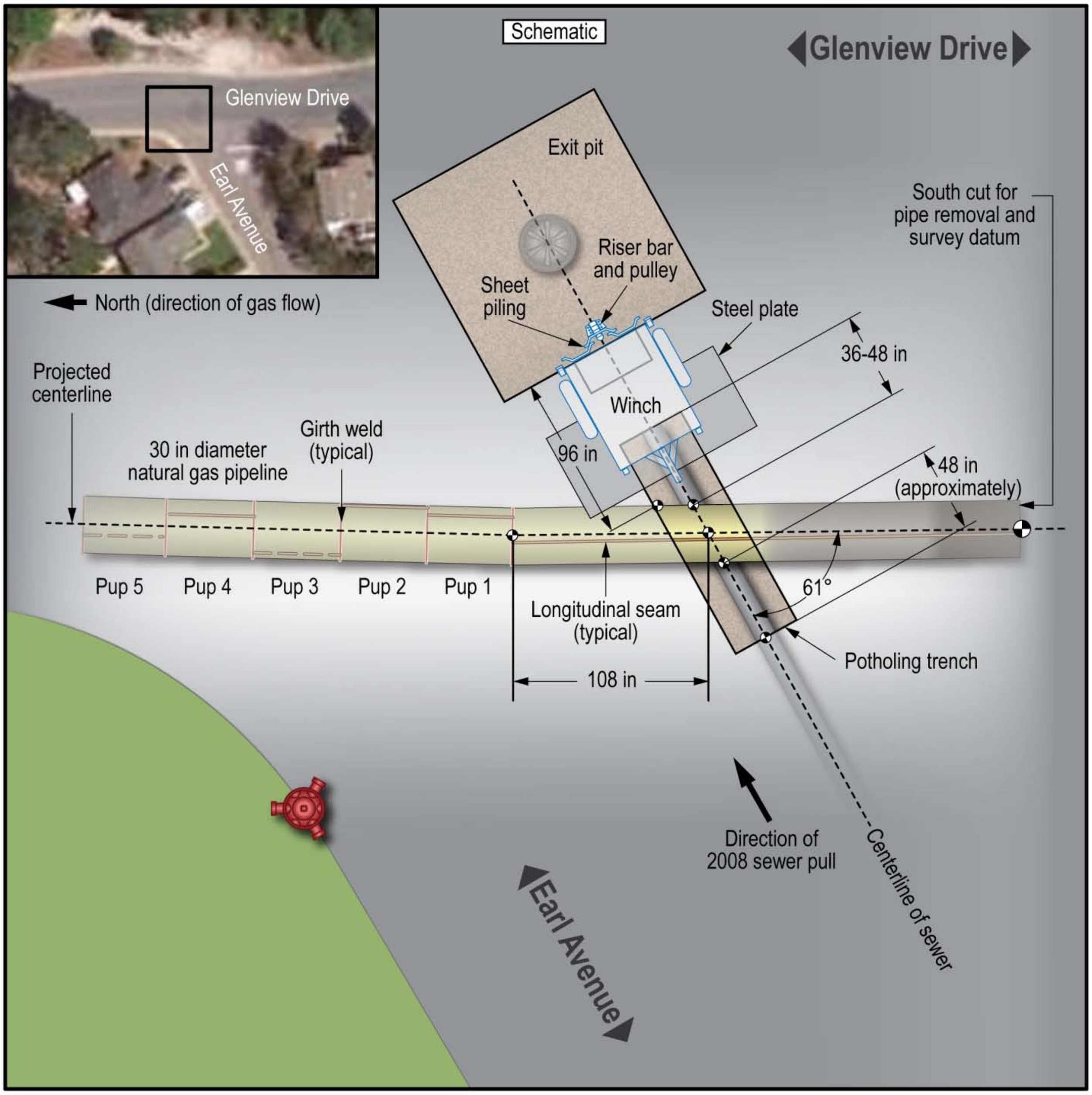

Figure 17. Diagram of excavations relative to Segment 180.

According to postaccident interviews, a PG&E gas mechanic was on site while part of the potholing trench was hand dug and after the polyethylene sewer pipeline had been pulled into the exit pit. The gas mechanic measured the vertical clearance between the bottom of Line 132 and the top of the new sewer pipeline, and determined that there was about 9 inches of clearance between the two. He also inspected the gas pipeline for damage and was satisfied with the work; he did not mention any problems or express any concern to the contractor foreman. The contractor proceeded to backfill the trench. The backfilling was neither witnessed nor inspected by the PG&E gas mechanic.

1.7.4.2 Guidelines for Pipe Bursting

Investigators reviewed studies that quantify safe distances for pipe bursting adjacent to utilities. According to one study,[49] there is a 95 percent probability that ground vibrations will be within safe levels for buried utilities at a distance of 7.5 feet or more from the bursting head, unless the buried utility is in poor structural condition. Nearby utilities and buried structures closer than 7.5 feet may require a small excavation (that is, potholing) in the bursting path to provide shielding from the vibration. Another report[50] concluded that the bursting head should not pass closer than 2.5 feet from buried pipes and 8 feet from sensitive surface structures. That report states that the problems related to nearby utilities are often relieved by localized excavations; to avoid damage, the general rule is that nearby utilities should be excavated whenever the vertical and horizontal separation is less than twice the replacement pipe diameter between the new pipe and existing utilities.

1.7.4.3 Pipe Bursting Study

Investigators used information from a land survey of the accident site, the above referenced studies on pipe bursting ground vibrations, a video of the Earl Avenue sewer replacement project, and the contractor's testimony to calculate the forces on Line 132 caused by the pipe bursting process. Investigators considered the effect of ground vibrations from the bursting head, constant loads from the winch at the exit pit, and vibratory loads from the winch at the exit pit. The calculations indicated that ground vibrations from the bursting head could have deformed pup 1 (where the rupture initiated) out-of-round by up to 0.004 inch. The effect of the deformation on the stress state of the pup 1 seam weld defect was less than a 6-psi change in internal gas pressure. The calculated external soil pressure on the side of pup 1 (approximately 10 feet from the winch brace), due to the 14,000-pound load on the sidewall of the exit pit, was 0.1 psi. This soil pressure had an effect on the stress state of the pup 1 seam weld defect equivalent to a 2.5-psi increase in internal gas pressure. The calculated variation in external soil pressure due to vibratory loads on the sidewall of the pit was less than 0.01 psi. The internal gas pressure on the day of the sewer replacement project was approximately 365 psig. In 2008, the gas pressure in Line 132 varied daily by up to 110 psi.

1.7.5 Pipeline MAOP

Prior to 1961, there were no regulations in the state of California governing natural gas pipeline safety. There was, however, a voluntary national consensus standard in ASME B31.1.8, 1955 edition, which called for hydrostatic pressure testing of newly constructed pipelines at 1.1–1.4 times the intended MAOP, depending on the class location. PG&E elected not to hydrostatically test Segment 180 of Line 132, and it is unknown if PG&E followed the other guidelines of the ASME standard.

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[49] A. Atalah, "The Ground Vibration Associated With Pipe Bursting in Rock Conditions," paper presented at *North American Society for Trenchless Technology, NO-DIG* 2004, *New Orleans, Louisiana, March 22-24, 2004*.

[50] J. Simicevic and R.L. Sterling, *Guidelines for Pipe Bursting*, TTC Technical Report #2001.02 (prepared by Trenchless Technology Center for U.S. Army Corps of Engineers, Engineering Research and Development Center, 2001).

In 1961, the CPUC began regulating natural gas pipeline safety in California under General Order 112, *State of California Rules Governing Design, Construction, Testing, Operation, and Maintenance of Gas Gathering, Transmission, and Distribution Piping Systems*, which was based on the ASME B31.1.8, 1958 edition. General Order 112 required hydrostatic pressure testing of newly constructed pipelines in class 3 areas at 1.5 times the intended MAOP, however it was not applied retroactively to existing installations such as Line 132. Therefore, PG&E was not required to pressure test Line 132 to comply with General Order 112.

Federal regulations issued in 1970 include a requirement in 49 CFR 192.505 that any segment of newly constructed gas transmission pipeline intended to operate at a hoop stress[51] of 30 percent or more of its SMYS undergo a hydrostatic pressure test for a minimum of 8 hours to substantiate its MAOP. In certain class 1 or 2 locations, the test pressure must be at least 125 percent of the MAOP; in class 3 and 4 locations, the required pressure is 150 percent of MAOP. The MAOP for a newly constructed pipeline segment is derived from the pressure used during this hydrostatic testing.

1.7.5.1 "Grandfather Clause"

For pipelines constructed before 1970 that were not required to be hydrostatically tested, 49 CFR 192.619(a) (3), known as the "grandfather clause," allows the MAOP to be based on "the highest actual operating pressure to which the segment was subjected during the 5 years preceding … July 1, 1970." In contrast to MAOP based on hydrostatic pressure testing, the grandfather clause does not specify a minimum amount of time that the historical pressure must have been held to be used as the basis for the MAOP.

As originally proposed, 49 CFR 192.619 did not include a grandfather clause but rather specified that the MAOP be set at the lowest of several alternatives, including (1) the design pressure of the weakest element in the pipeline system or (2) a percentage, based on the class location, of the pressure to which the pipeline was tested after construction. However, the Federal Power Commission (the predecessor of the Federal Energy Regulatory Commission) submitted comments on the proposed rule, pointing out that the proposed MAOP limits were similar to those in the ASME-sponsored B31.8, 1968 edition, *Gas Transmission and Distribution Piping Systems*. The Federal Power Commission stated—

> The proposed regulation does not recognize that the B31.8 Code did not establish these minimum test levels until 1952. Prior to that time, between 1935 and 1951, the predecessor Code, B31, required only that a pipeline be tested to a pressure 50 [psig] in excess of the proposed maximum operating pressure.
>
> There are thousands of miles of jurisdictional interstate pipelines installed prior to 1952, in compliance with the then existing codes, which could not continue to operate at their present pressure levels and be in compliance with [the] proposed section [].

[51] A hoop stress is a circumferential stress in thin-walled cylinders (for example, the internal diameter is greater than 40 times the wall thickness) and is assumed to be approximately uniform through the thickness of the wall.

> The [Federal Power] Commission has reviewed the operating record of the interstate pipeline companies and has found no evidence that would indicate a material increase in safety would result from requiring wholesale reductions in the pressure of existing pipelines which have been proven capable of withstanding present operating pressure through actual operation.

The preamble to the final rule establishing Part 192 stated—

> [i]n view of the statements made by the Federal Power Commission, and the fact that [the U.S. Department of Transportation (DOT)] does not now have enough information to determine that existing operating pressures are unsafe, a 'grandfather' clause has been included in the final rule to permit continued operation of pipelines at the highest pressure to which the pipeline had been subjected during the 5 years preceding July 1, 1970.[52]

In 1987, the NTSB recommended elimination of the grandfather clause in Safety Recommendation P-87-9. In 1989, the Research and Special Programs Administration (RSPA), the predecessor agency of PHMSA, issued an advance notice of proposed rulemaking (ANPRM) inviting public comment on whether the grandfather clause should be eliminated.[53] The ANPRM noted that the grandfather clause allowed certain pipelines to operate at hoop stress levels above 72 percent of SMYS, whereas nongrandfathered pipes were limited to 72 percent of SMYS. The ANPRM also noted that the NTSB had recommended elimination of the grandfather clause. Based on public comments received on the 1989 ANPRM, RSPA decided not to eliminate the grandfather clause. (For more information on Safety Recommendation P-87-9 and the ANPRM, see section 1.12, "Previous NTSB Safety Recommendations.")

PHMSA statistics indicate that 61 percent of onshore gas transmission pipelines (about 180,000 miles) were installed prior to 1970. PHMSA does not keep track of how many of these pipelines have MAOPs established under the grandfather clause.

1.7.5.2 MAOP for Line 132

The MAOP for Line 132 was established as 400 psig pursuant to the grandfather clause. According to PG&E logs from the Milpitas Terminal, the highest operating pressure on Line 132 during the applicable 5-year period was 400 psig on October 16, 1968.

The MOP set by PG&E for Line 132 was 375 psig. According to the manager of the PG&E integrity management program, PG&E considers the MOP to be the maximum pressure at which a pipeline system, as distinguished from a pipeline segment, can operate. She explained that the MOP of a pipeline system is governed by the lowest MAOP of any interconnected lines. Thus, when crossties connecting Line 132 (MAOP of 400 psig) and Line 109 (MAOP of 375 psig) are open, the MOP of Line 132 is the MAOP of Line 109—that is, 375 psig.

[52] *Federal Register*, vol. 35, no. 161 (August 19, 1970), p. 13248.

[53] *Federal Register*, vol. 54, no. 236 (December 11, 1989), p. 50780.

1.7.5.3 Periodic Pressure Increases to MAOP

Title 49 CFR 192.917(e) addresses required actions for particular threats. It is one of the integrity management program rules that became effective in 2004 [54] and states, in part:

> (3) *Manufacturing and construction defects.* If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered[55] segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.
>
> (i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;
> (ii) MAOP increases; or
> (iii) The stresses leading to cyclic fatigue increase.
>
> (4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW),[56] lap welded pipe or other pipe that satisfies the conditions specified in ASME B31.8S,[57] Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

PG&E had a practice of raising the operating pressure to MAOP once every 5 years on several of its pipelines, including Line 132 and the other peninsula lines (Lines 101 and 109), as a strategy to continue classifying any manufacturing and construction defects on those lines as "stable," meaning that they were not anticipated to grow in service.

[54] For more information about integrity management programs, see Section 1.10.2, "Federal Oversight by PHMSA."

[55] A covered segment is defined in 49 CFR 192.903 as a segment of a gas transmission pipeline located in a high consequence area (HCA).

[56] Line 132 includes several ERW segments.

[57] ASME-sponsored code B31.8S, 2004 edition, *Managing System Integrity of Gas Pipelines: ASME Code for Pressure Piping, B31 Supplement to ASME B31.8.*

According to PG&E, the pressure on Line 132 was raised to 400 psig at the Milpitas Terminal in December 2003 and December 2008 for about 2 hours each time. During the pressure increase, the downstream pressures at the Martin Station in 2003 and 2008 were 383 psig and 382 psig, respectively, due to the normal pressure gradient. PG&E acknowledged in response to inquiries from NTSB investigators that the pressure needed to serve customers is not usually the MAOP. However, PG&E went on to explain that—

> under certain circumstances where the operating pressure is raised above the maximum pressure experienced during the preceding [5] years, PHMSA regulations … require the operator to schedule a priority assessment capable of assessing seam integrity. In these circumstances, ASME B31.8S calls for a hydrostatic pressure test, which would take a line out of service for a period of at least a week. To avoid this and any potential customer curtailments that may result, PG&E has operated, within the applicable 5-year period, some of its pipelines that would be difficult to take out of service at the maximum pressure experienced during the preceding 5-year period in order to meet peak demand and preserve the line's operational flexibility.

The regulatory history of 49 CFR 192.917(e)(3) indicates that the rule as originally proposed called for a one-time pressure test to address manufacturing and construction defects.[58] However, the final rule[59] did not include this requirement. The preamble to the final rule explained:

> [PHMSA] has been convinced by the public comments, including discussions at the public meetings, that it is not necessary to require a once-in-a-lifetime pressure test to address the threat of material and construction defects. Historical safe operation, which in many cases involves several decades, provides confidence that latent defects will not result in pipeline failure as long as operating conditions remain unchanged. The final rule requires that an assessment be performed if operating pressure is increased above the historic level or if operating conditions change in a manner that would promote cyclic fatigue.

At the NTSB investigative hearing, the PHMSA deputy associate administrator for field operations testified that, "it was not the intent when the regulation was written that it would warrant the raising of pressures to avoid a certain assessment. If you're adjusting the pressure periodically, you need to … make that part of your overall assessment of the risk on that pipeline." The CPUC director of consumer protection and safety division stated that the CPUC did not agree with the PG&E interpretation of 49 CFR 192.917, and commented that the practice of "artificially raising the pressure in a pipe that has identified integrity seam issues seems to be a wrong-headed approach to safety." PHMSA officials were unaware of any other operators following such a practice.

[58] *Federal Register*, vol. 68, no. 18 (January 28, 2003), pp. 4278, 4318.

[59] *Federal Register*, vol. 68, no. 240 (December 15, 2003), pp. 69817, 69791.

A study that looked at the stability of manufacturing- and construction-related defects is discussed in Gas Research Institute (GRI)[60] report GRI-04/0178, *Effects of Pressure Cycles on Gas Pipelines*, dated September 17, 2004:

> the risk of pressure-cycle-induced fatigue can be dismissed if and only if the pipeline has been subjected to a reasonably high-pressure hydrostatic test. Therefore, it would seem that eliminating the risk of failure from pressure-cycle-induced fatigue crack growth of defects that can survive an initial hydrostatic test of a pipeline requires that the test pressure level must be at least 1.25 times the maximum operating pressure.

A PHMSA report from 2007, No. 05-12R, *Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines*, also looked at defect stability and concluded the following:

> To summarize, experience and scientific analysis indicates that manufacturing defects in gas pipelines that have been subjected to a hydrostatic test to 1.25 times MAOP should be considered stable. No integrity assessment is necessary to address that particular threat in such pipelines. The principal challenge for deciding whether or not to consider manufacturing defects to be stable is associated with those gas pipelines that have never been subjected to a hydrostatic test to a minimum of 1.25 times MAOP.

1.7.6 History of Seam Defects in PG&E Gas Transmission Pipelines

On May 20, 2011,[61] the NTSB learned that a DSAW segment on Line 132 had experienced a longitudinal seam leak in October 1988 at MP 30.44, about 8.78 miles south of the San Bruno rupture. Until May 6, 2011, the PG&E GIS had listed the cause of the leak as "unknown." However, as a result of records discovered during a PG&E postaccident records search,[62] information was added to indicate that 12 feet of Line 132 had been replaced "due to a longitudinal defect." A leak survey inspection and repair report dated October 27, 1988, classified the cause of the leak as a "material failure" and indicated that a material failure report was prepared, but PG&E could not locate any such report. Records showed that the replacement work had started on November 1 and been completed on November 4, 1988. No further information was available regarding the cause of the leak.

Seam leaks or test failures in PG&E gas transmission pipelines are listed in table 2.

[60] In 2000, the GRI combined with the Institute of Gas Technology to form the Gas Technology Institute (GTI), a nonprofit research and development organization that develops, demonstrates, and licenses new energy technologies for private and public clients, with a particular focus on the natural gas industry. PG&E is a member of the GTI.

[61] Shortly after the September 9, 2010, rupture, NTSB investigators asked PG&E to provide a leak/repair history for Line 132. However, this information was not provided until 8 months after the accident.

[62] For more information about this records search, see Section 1.11.1, "Actions Taken by PG&E."

Table 2. PG&E gas transmission pipeline seam leaks or test failures, 1948–2011.

Year Found	Line	Pipeline Diameter (inches)	Description
1948	132	30	Multiple longitudinal seam cracks found during radiography of girth welds during construction
1958	300B	34	Seam leak in DSAW pipe
1974	300B	34	Hydrostatic test failure of seam weld with lack of penetration (similar to accident pipe)
1988	132	30	Longitudinal seam defect in DSAW pipe
1992	132	30	Longitudinal seam defect in DSAW weld when a tie-in girth weld was radiographed
1996	109	22	Cracking of the seam weld in DSAW pipe
1996	109	22	Seam weld with lack of penetration (similar to accident pipe) found during camera inspection
1996	DFM-3	--	Defect in forge-welded seam weld
1999	402	16	Leak in ERW seam weld
2011	300A	34	Longitudinal seam crack in 2-foot pup of DSAW pipe (found during camera inspection)
2011	153	30	Longitudinal seam defect in DSAW pipe during radiographic inspection for validation of seam type

1.7.7 Protection Against Accidental Overpressure

Title 49 CFR 192.195, "Protection Against Accidental Overpressuring," requires "each pipeline that is connected to a gas source so that [MAOP] could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of [sections] 192.199 and 192.201." Section 192.201, in turn, requires—for pipelines operated at 60 psig or higher—that such devices must ensure that the pipeline pressure does not exceed MAOP plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower.

1.8 Examination of Accident Pipe

The ruptured section of pipe and two cutout sections of pipe, immediately south and north of the ruptured section, as illustrated in the figure 18 schematic, were examined at the NTSB Materials Laboratory. The southern[63] section of pipe consisted of a single portion of pipe (commonly referred to as a joint).[64] The center section (the ruptured section found about 100 feet from the crater) was fractured at both ends and comprised a continuation of the same long joint from the southern section as well as four shorter lengths of pipe (pups). The northern section of pipe comprised two more pups and a portion of another long joint. For convenience, the pups were numbered 1–6 in the south-to-north direction. The girth welds that joined the pups were numbered sequentially from south to north as C1, C2, and so on through C7.

[63] "Southern" refers to the north-south alignment of the pipeline prior to the accident.

[64] A joint is a single length of pipe, typically 20 feet or greater in length.